ISSN 2347-4289

Green-Based Generation Expansion Planning For Kenya Using Wien Automatic Software Package (WASP) IV Model.

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ABSTRACT: In 21st Century, there is growing interests in the global power generation sector to integrate more renewable energy (RE) resources in least-cost generation expansion planning for security of supply and sustainable development. However, little has been done in Kenya yet she was endowed with enormous unexploited RE resources. For this reason, the study derived an optimal green least-cost generation expansion plan (OGLCGEP) taking 2010 as the base year to 2031 using the WASP IV model. The study findings showed that the OGLCGEP had a capacity of 1382MW at a peak demand of 1227MW in the base year. However, annual RE capacity additions over the planning horizon will raise the capacities to 19828MW at a peak demand of 16905MW in the reference demand forecast scenario (RDFS) and 26968MW at a peak demand of 22985MW in the higher demand forecast scenario (HDFS). Consequently a 71% to 78% green generation would be realized with 1.94 -3.02 % LOLP. Additionally, the envisaged RE system would supply 7721GWh to 105766 GWh in the RDFS and 143830GWh in the HDFS with a cumulative total of 18 to 23.6Mt CO_2 emissions. Moreover, the energy system's cost would be US$ 14.62 billion in the RDFS; US$ 5.34 billion higher in the HDFS by 2031. Subsequently, the system's net present value would be US$ +2.16 billion in the RDFS; US$ +4.92 billion higher in the HDFS besides potential carbon credits. Thus, the OGLCGEP would be a feasible option and the future for high RE grid integration for Kenya. Therefore, the research recommends future studies to focus on modeling of the Kenya national-grid reliability and stability with high penetration of variable renewable energy sources.

Keywords : Generation Expansion Planning; Renewable energy; WASP IV; Optimal Solution; Senstivity Analysis; CO_2 emissions; net present value

1.0 INTRODUCTION

The world power generation sector is projected to undergo unprecedented demand growth from 17,408 TWh in 2004 to 33,750 TWh in 2030 at an average annual growth rate of 2.6%. To meet this demand, the sector will built 5,087GW of which over 75% will come from oil, coal and gas power plants. Consequently, the carbon-intensive plants are expected to rise the CO2 emissions from 9600-16400Mt at an annual growth rate of 2%. The rapidly increasing global emission is the major cause of global climate change [1]. Consequently, the global generation sector is faced with enormous pressure to lead the way in climate change mitigation strategies. Thus generation companies (GENCOs) in many countries in the world are currently planning towards environmentally-friendly generation investments [1], [2]. The most popular energy policy measure towards this course is the use of Renewable energy (RE) as suitable clean energy option to the conventional carbon intensive plants [3], [4]. Subsequently, more integration of RE in the power system's least-cost generation expansion planning (GEP) is rapidly gaining extraordinary consideration as a sustainable option to security of power and CO2 emission reduction [5], [6]. The system integration also presents a significant potential for carbon credits as revenues in the generation sector from the carbon market [7], [8], [9]. Furthermore, other fringe benefits such as health benefits, green jobs and foreign exchange savings prevail for sustainable development [10], [11]. In Kenya, the generation sector prepares 20 year rolling least cost power development plan (LCPDP) at the energy regulatory commission (ERC) for expanding the power system to meet the current and future power demands. The 2011-2031 LCPDP under the focus of this study had projected a hydropower and heavy fuel oil (HFO) dominated power generation [12] that posed serious challenges. The hydros were vulnerable to acute energy shortfalls due to the frequent droughts. On the other hand, the HFO and the planned conventional coal plants posed the CO2 emissions dilemma [13], [14]. These were crucial issues for urgent attension by energy planners. As a matter of fact, Kenya is well placed to plan for exploitation of these enormous candidate energy resources. The 60MW Mutonga and 140MW LGF hydropower sites were due for immediate development [14]. Besides; 7600MW unexploited feasible geothermal prospects existed for shifting the base load generation from the vulnerable hydropower [15]. Moreover, the Kenya's strategic location along the equator offered about 638, 790 TWh solar PV potential as a potential peaking substitute for the expensive HFO power [16]. Furthermore, the huge potential of about 346W/m2 and wind speeds of over 6ms-1 existed for wind power generation base load penetration besides geothermal [17]. Since, an effective green generation portfolio requires a proportion of other resources for reliability and stability [5]; there were at least 2000MW hydropower imports from Ethiopia, about 2340MW natural gas and about 4000MW nuclear potential for Kenya's utilization [12]. A study on selecting RE candidate plants for green-based GEP for Kenya using the screening curvewas was undertakeng by [18]. The research established that 140MW Geothermal, 140MW low grand falls hydro, 300MW Wind, 1000MW imports, 60MWMutonga hydro and 1000MW nuclear plants were suitable base load plants. On the other hand, 180MW GT-Natural and 100MW Solar PV plants were peaking plants besides part of the imports. The research recommeded the use of these candidates in simulation and optimization of the optimal green least-cost generation expansion plan (OGLCGEP) for Kenya using relevant GEP modelsTherefore, this study sought to explore the recommendations using the Wien Automatic software package (WASP) IV. This paper is divided into five sections. The section two gives an overview of the methodology. Section three presents the research results. Section four outlines the discussion. Section five gives the conclusions and recommendations on future research.

ISSN 2347-4289

2.0 METHODOLOGY

2. 1 WIEN AUTOMATIC SYSTEM PLANNING (WASP) IV

The Wien Automatic software package (WASP) is the most frequently used and best proven model for GEP analysis worldwide. It is developed and maintained by the International Atomic Energy Agency (IAEA) for free to its member states. WASP IV model is the fourth versions of WASP have been developed and distributed worldwide [19], [25]. It is systematic and modular consisting of various modules and associated files. Suitable batch files are provided in the model for executing different modules. However, correct input data should be provided for each module for creating input files prior to the execution process [19], [20]. The first three modules are for basic input data on the demand forecast, candidate generation plants as well as committed plants. These include; **load sy**stem (LOADSY), **fix**ed **sy**stem (FIXSYS) and **var**iable **sys**tem (VARSYS) respectively. The three modules are executed independently of each other. The next four modules namely; **con**figuration **gen**erator (CONGEN), **mer**ge and **sim**ulate (MERSIM), **Re**-**mer**ge and **sim**ulate (REMERSIM) and **dyn**amic **pro**gramming (DYNPRO) are executed after analyzing the first three. The WASP IV model is accomplished with powerful attributes to address new and emerging issues in the generation sector in late 1990s [19], [21]. The new features incorporated include:

- Options for environmental emissions, fuel usage and energy generation constraints
- Representation of pumped-storage plants
- Fixed maintenance schedule
- Environmental emission calculations
- Expanded capabilities for handling up to 90 plants types and

500 configurations per year. The model attributes designed in an enhanced dynamic programming (DP) algorithm incorporated with heuristic technique is capacable of deriving the optimal solution for generation capacity addition that meets the energy demand for at most 30 years. Fundamentally, the evaluation of the optimal solution is based on minimizing the objective cost function that represents the generation energy system's cost that consists of the existing and candidate plants. The objective function is defined as the sum of the construction costs, operation & maintenance costs (including fuel costs) and the cost of energy not served, less the salvage value of the generation investment. These cost function is subject to reliability, tunnel (construction), fuel availability and emission constraints [16], [21], [25]. In the WASP IV model, the system's costs are simulated through probablistic product cost (PPC) besides the generation costs, cost of energy not served and reliability (LOLP). The linear programming is used in establishing the optimal generation dispatch plan that fulfills environmental emissions, fuel availability and energy generation (by some plants) constraints. Subsequently, the enhanced DP optimization evaluates the costs of the alternative system expansion policies and derives the optimum solution [19]. The PPC technique is affirmed by [20], [22] as the best analytical framework that GENCOs use when evaluating generation cost taking risks into account. However, the generation projects are capital intensive and often stay for long hence their financial flows occur after some years. Hence, present valuing (discounting) of their costs and benefits to their PV enable proper project evaluation. A choice of a proper discount rate cushions inflation and other investment uncertainties [5], [21], [25], [26]. As a matter of fact, discounting (time value of money) has featured widely in literature for evaluating power generation projects. In this way, reliable financial techniques such as the net present value (NPV), future worth value (FWV) and internal rate of return (IRR) are applied extensively. The NPV is the most effective financial project evaluation technique [14], [23], [26]. Additionally, the economics of system generation reliability often strike a balance between cost and quality of service. Typically, the long-run marginal cost (LRMC) is the levelised cost where the marginal utility for the extra reliability enhancement to the consumer equals the marginal cost spent by the power supplier. In this way, the LRMC serves as the basis for establishing the electricity tariffs [5], [26], [24]. Therefore, the impressive simulation and optimization features in WASP IV model has made it a popular tool for solving many GEP problems in various countries around the world [25], [21], [26].

2.2 MODELING THE OGLCGEP

In these study two scenarios; the reference demand forecast scenario (RDFS) and the higher demand forecast scenario (HDFS) were considered. The RDFS assumed Kenya's demand projections incorporated with energy requirements for part implementation of the Vision 2030 flag-ship projects. On the other hand, the HDFS assumed the country's demand forecast integrated with energy demands for full implementation of all the flagship projects. Subsequently, the optimal green least-cost generation expansion plan (OGLCGEP) for Kenya was simulated and optimized in WASP IV. Additioanally, sensitivity analyses were undertaken on the derived optimal solution. Fig 1 shows the WASP IV methodology for the study. The data to input data modules in WASP IV was as follows: the demand forecast to LOADSY, the existing & committed plants' characteristics to FIXSYS and candidate generation plants to VARSYS. The modules were executed independently from each other by appropriate model batch files. The next five modules namely; CONGEN, MERSIM, REMERSIM, DYNPRO and REPROBAT were executed after reviewing the first three. In case of any error, an interruption to the program execution generated an error message. Proper debugging and re-running the program ensured successful execution of each module. Successful execution of each module showed 'FILES ARE CLOSED' message. The LOADSY, FIXSYS and VARSYS outputs were input data to CONGEN in the RDFS and HDFS. In CONGEN, the tunnel width for each candidate plant was specified for each year for optimization. Subsequently, CONGEN-MERSIM-DYNPRO sequential run was undertaken without changing any input to the other modules. After the initial successful run, a number of CONGEN iterations and sequential runs were performed to obtain the OGLCGEP in DYNPRO in each scenario. The REBROBAT module provided a summary of the attributes of the OGLCGEP namely generation capacity, energy, reliability and energy system's cost in each case. Careful analysis of DYNPRO messages prior to new subsequent CONGEN iterations and runs was essential in the optimization process. As a rule of thumb, new iterative run(s) were prepared by increasing the minimum number of plants marked with (+) by one and decreasing by one those marked by (-) in CONGEN. However, preference in the study was given to the selected RE candidates without going beyond their tunnel boundaries.

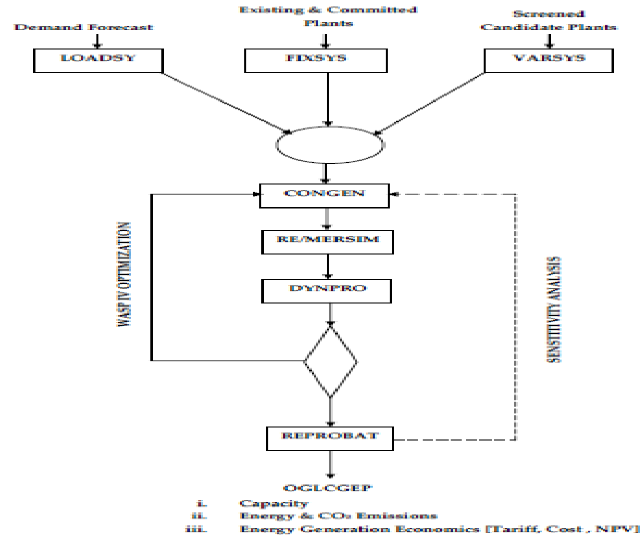

Figure 1: *WASP IV GEP Methodology*

The optimization process minimized certain cost components in the objective cost function in DYNPRO discounting the energy system's cost at an 8% discount rate subject to capacity, technology and operational constraints. The objective function (***B**$_j$*) represented by the equation (1) is composed of: capital investment costs (I), fuel costs (F), operation and maintenance (O&M) costs (M), fuel inventory costs (L), salvage value of investments (S) and cost of energy demand not served (**ø**). The planning period of time (**t**) was given in years while ***T*** **(**22) was the length of the study period in years.

$$B_j = \sum_{t=1}^{T}\{I_{it} - S_{it} + F_{it} + L_{it} + M_{it} + \emptyset_{it}\} \qquad (1)$$

2.3 OGLCGEP CO_2 Emissions

The CO_2 emissions for the OGLCGEP in the RDFS and the HDFS were determined using the emission factors from the 2014 US Climate Registry. In each scenario, the energy technologies considered varied in the emission factors based on their environmental pollution extents. Table 1 displays the emission factors for the energy generation technologies considered in the study.

Table 1: *Emission Factors for Energy Generation Technologies*

SNo.	Energy Technology	$TonCO_2$/GWh
1	Baggase	301.8014
2	Kerosene	246.8583
3	HFO	249.7988
4	Natural gas	181.2356
5	Geothermal	25.6918

The annual CO_2 emission for the given energy technology in the planning period was computed using equation (1).

$$AnnualEmission_{e\_technology}(tonCO_2) = \{G\_Energy_{e\ t}[GWh]\ X\ Emission\ Factor_{e\ t}\} \qquad (2)$$

The total CO_2 emission for each technology in the period was established as the sum of the annual emissions in each scenario.

2.4 OGLCGEP Generation Economics

Most economic costs of generation for the OGLCGEP were directly in the energy system's cost function in equstion 1. However, the average cost per unit generated was determined indirectly using the long-run marginal cost (LRMC); the most convenient approach for calculating power tariffs recognized by IES, (2004). In the LRMC, two optimal generation programs were considered in the WASP IV. The first program was essentially the OGLCGEP derived for the given demand forecast (RDFS or HDFS) while the second under an incremental load on the demand forecast. The REPROBAT results on the energy, operation cost and capital cost for each program was utilized to generate a LRMC model in Microsoft Excel for the planning period. Additionally, the corresponding energy, operation cost & capital cost differences; LRMC factors (0.20 to 1.00) and energy discounts comprised essential LRMC model constituents. Fig 2 shows the LRMC model for the OGLCGEP.

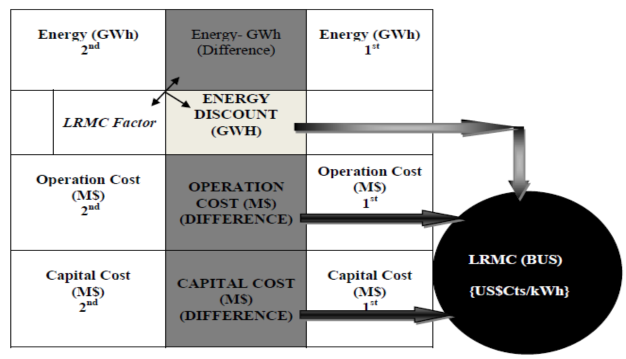

Figure 2: *LRMC Model for the OGLCGEP*

The energy discount was computed using equations (3). Additionally, the operation and capital cost differences were crucial in the LRMC calculation at the bus as shown in equations (4).

$$EnergyDiscount\ \{GWh\} = \{EnergyDifference\ X\ LRMC\ Factor\} \qquad (3)$$

$$LRMC(bus\ \{US\$cts/kWh\}) = \frac{\sum[OperationCostDiff\ .(M\$)]}{\sum[EnergyDiscount\ \ (GWh)]} + \frac{\sum[CapitalCostDiff\ .(M\$)]}{\sum[EnergyDiscount\ \ (GWh)]} \qquad (4)$$

Consequently, the PV inflows were calculated using equation (5) and the net present value (NPV) as the long-term future revenues for the OGLCGEP determined using equation (6).

$$Annual\ PV\ Inflows = \{Energy\ Generated\ X\ \mathbf{Cost\ per\ Unit\ Generated}\} \qquad (5)$$

$$Annual\ Net\ Present\ Value = \{\mathbf{PV\ Inflows} + Salvage\ Value - System's\ Cost\} \qquad (6)$$

2.5 OGLCGEP Sensitivity Analyses

During the planning period, economic factors such as the discount rate; fuel cost and capital cost were anticipated to change over time. In this way, sensitivity analyses were conducted to identify the effect of changes in these economic factors on the energy system's cost and NPV of the

OGLCGEP. Therefore, the study involved varying each of the given economic factors in DYNPRO at definite steps for the RDFS and the HDFS. Thus, the discount rate was varied from 8% to 12% in steps of 2%; the fuel cost from 10% to 30% in steps of 10% and finally the capital cost from 5% to 15% in steps of 5%. A re-run of DYNAPRO was undertaken where the variations retained the OGLCGEP within its initial CONGEN tunnel boundaries. However, in cases where the changes blew the tunnel boundaries, few CONGEN iterations and CONGEN-MERSIM-DYNPRO re-runs were executed to attain a new unconstrained OGLCGEP.

3.0 Results

3.1 Reference Demand Forecast Scenario(RDFS)

3.1.1 Capacity Mix

The optimal solution of adding new capacities annually for the selected RE candidate plants was obtained for the 2011-2031 planning period. The capacity additions were derived taking into account the technical, economic and environmental constraints that directly influenced availability of candidates for capacity addition. Table 2 presents the RE capacity addition schedule in the RDFS. The results show that the initial capacity addition will be 420MW from geothermal. This will be increased gradually to17380MW by 2031. In total, geothermal will have the highest additions at 42.7%. The least will be from hydro and solar PV each at 1.2%.

Table 2: *OGLCGEP RE Capacity Addition Schedule (MW) – RDFS*

Year	Geothermal (140MW)	Wind (100MW)	Nuclear (600MW)	Imports (200MW)	Natural Gas (180MW)	Solar PV (100MW)	Mutonga Hydro (60MW)	LGF (140MW)	Total Added Capacity(MW)
2010	-	-	-	-	-	-	-	-	0
2011	-	-	-	-	-	-	-	-	0
2012	3×140	-	-	-	-	-	-	-	420
2013	-	-	-	-	-	-	-	-	0
2014	-	-	-	-	-	-	-	-	0
2015	1×140	-	-	-	-	-	-	-	140
2016	2×140	-	-	-	1×180	-	-	-	460
2017	1×140	1×100	-	1×200	1×180	-	-	-	620
2018	-	1×100	-	1×200	-	-	1×60	1×140	500
2019	1×140	1×100	-	2×200	-	-	-	-	640
2020	2×140	-	-	1×200	-	-	-	-	480
2021	3×140	1×100	-	1×200	-	-	-	-	720
2022	2×140	5×100	-	-	-	-	-	-	780
2023	1×140	-	1×600	-	-	1×100	-	-	840
2024	3×140	1×100	-	1×200	1×180	-	-	-	900
2025	5×140	3×100	-	1×200	-	-	-	-	1200
2026	5×140	4×100	-	-	-	-	-	-	1100
2027	3×140	2×100	-	-	4×180	-	-	-	1340
2028	6×140	5×100	-	1×200	-	-	-	-	1540
2029	5×140	-	1×600	1×200	1×180	-	-	-	1680
2030	3×140	-	1×600	1×200	3×180	1×100	-	-	1860
2031	7×140	10×100	-	-	1×180	-	-	-	2160
Total	**53**	**34**	**3**	**11**	**12**	**2**	**1**	**1**	**117**
	7420	**3400**	**1800**	**2200**	**2160**	**200**	**60**	**140**	**17380**
%	**42.7%**	**19.6%**	**10.4%**	**12.7%**	**12.4%**	**1.2%**	**1.2%**		**100%**

When the RE capacity additions were integrated in the exiting generation system; the OGLCGEP capacity in the RDFS was derived as shown in table 3 and fig 3. The results show that the generation capacity was 1382MW at a peak demand of 1227MW in the base year. This was predominated by hydropower (55%) and HFO (24%). In comparison to the rest of the planning period, the generation system had the least reserve capacity hence the highest LOLP of 23.3%. The rising RE capacity additions at an average rate of 901MW per annum projected to vary the system's capacity in the base year to 19828MW at 16905MW peak demand in 2031. The generation capacities would be characterized by low LOLPs averaged at 1.94%. By 2031, the generation capacity would be 78% green and dominated by geothermal (40.8%) wind (19.2%).

Table 3: *OGLCGEP Capacity (MW) – RDFS*

Year	Hydropower	Natural Gas	HFO	Nuclear	Imports	Bagasse	Kerosene	Geothermal	Solar PV	Wind	Capacity	Peak Load	% LOLP
2010	761	0	332	0	0	26	60	198	0	6	1382	1227	23.265
2011	761	0	452	0	0	26	60	198	0	6	1502	1302	6.669
2012	761	0	452	0	0	26	60	626	0	6	1929	1520	0.118
2013	761	0	704	0	0	26	60	791	0	126	2466	1765	0.003
2014	814	0	704	0	0	26	0	1211	0	476	3229	2064	0.006
2015	839	0	704	0	0	26	0	1306	0	476	3349	2511	0.019
2016	839	180	704	0	0	26	0	1586	0	476	3809	2866	0.007
2017	839	360	704	0	200	26	0	1771	0	576	4474	3292	0.016
2018	1039	360	704	0	400	26	0	1771	0	676	4974	3751	0.008
2019	1039	360	648	0	800	0	0	1911	0	776	5532	4216	0.023
2020	1039	360	648	0	1000	0	0	2191	0	776	6012	4755	0.091
2021	1039	360	574	0	1200	0	0	2611	0	876	6658	5388	0.223
2022	1039	360	574	0	1200	0	0	2891	0	1376	7438	6048	0.773
2023	1039	360	514	600	1200	0	0	3031	100	1376	8218	6784	1.244
2024	1039	540	514	600	1400	0	0	3451	100	1476	9118	7608	1.208
2025	1039	540	461	600	1600	0	0	4151	100	1776	10266	8528	1.051
2026	1039	540	461	600	1600	0	0	4851	100	2176	11366	9556	1.546
2027	1039	1260	461	600	1600	0	0	5271	100	2376	12706	10706	1.276
2028	1039	1260	461	600	1800	0	0	6063	100	2876	14198	11994	1.539
2029	1039	1440	461	1200	2000	0	0	6763	100	2876	15878	13435	1.092
2030	1039	1980	461	1800	2200	0	0	7113	200	2876	17668	15026	1.006
2031	1039	2160	461	1800	2200	0	0	8093	200	3876	19828	16905	1.595
%	**5.2%**	**10.9%**	**2.3%**	**9.1%**	**11.1%**	**0.0**	**0.0**	**40.8%**	**1.0%**	**19.5%**	**100%**		**1.94**

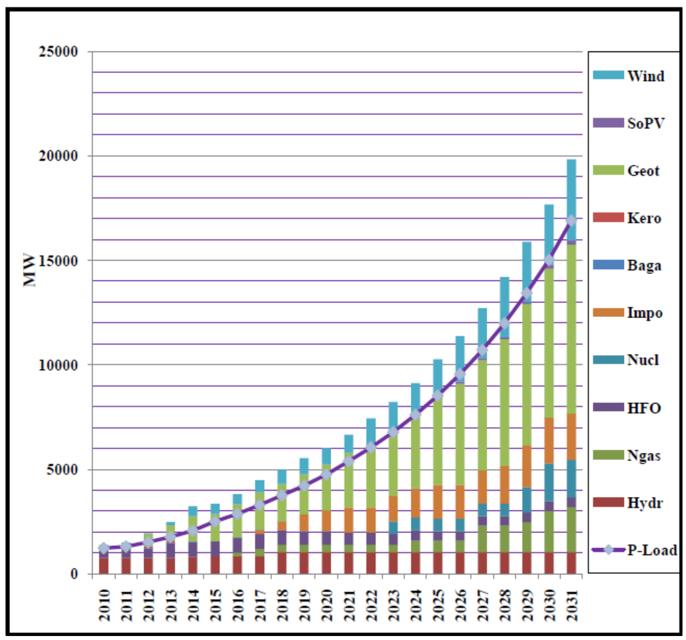

Figure 3: *OGLCGEP Capacity (MW) – RDFS*

3.1.2 Energy and CO_2 Emissions

The generated energy OGLCGEP was projected to grow steadily over the entire planning horizon while meeting the requisite demand. Fig 4 presents the OGLCGEP energy mix for the RDFS. The results show that the supply mix will rise steadily from 7721GWh in the base year to 105766GWh in 2031.

ISSN 2347-4289

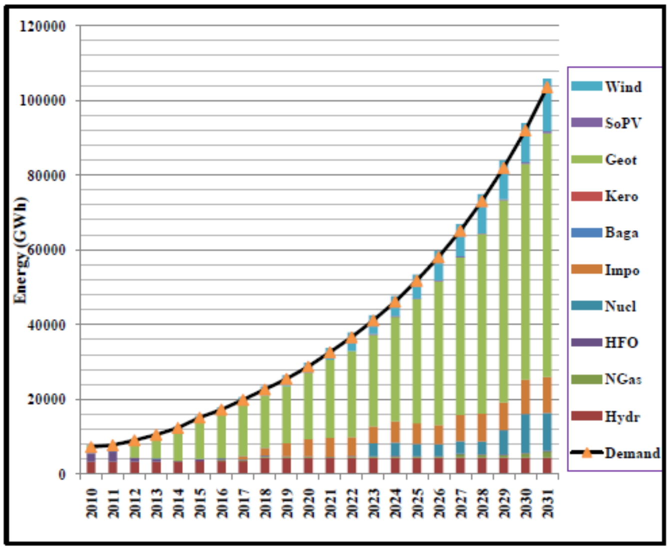

***Figure 4:** OGLCGEP Energy Mix (GWh) – RDFS*

Consequently, the energy system would emit some CO_2 emissions over the planning period. Fig 5 illustrates the profile for the CO_2 emissions for the OGLCGEP in the RDFS. The results show that the annual emissions would grow from 0.73 Mt CO_2 in the base year to 2 Mt CO_2 in 2031. In the base year, HFO would be the highest emitter at about 77.8% of the total. However the trend would depart to majorly geothermal with increasing annual RE supply additions over the planning period by 2031. By the end of the planning period, a cumulative total of 18Mt CO_2 at the average rate of 0.82 Mt CO_2 per year would be emitted. Geothermal will be the highest emitter at 77% of the total. Other RE such as hydropower, wind and solar PV will have any emissions.

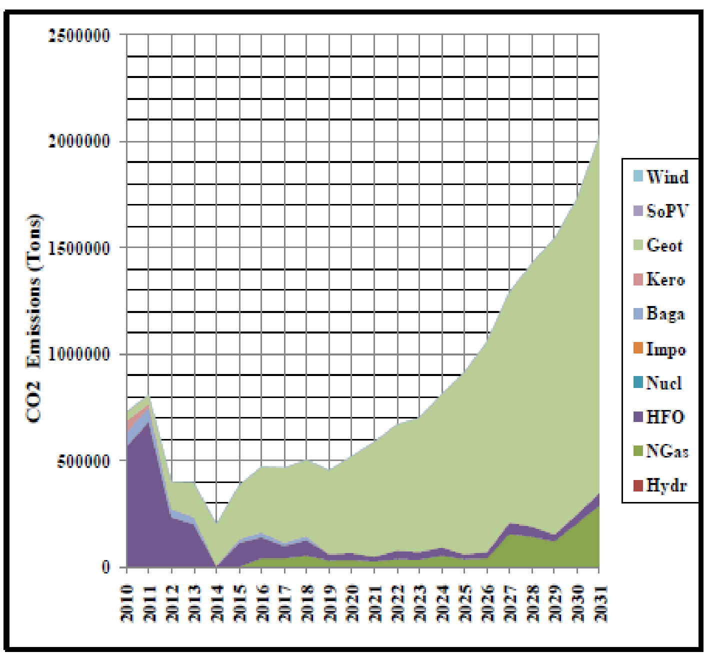

***Figure 5:** OGLCGEP CO_2 Emission – RDFS*

3.1.3 Generation Economics

The average power tariff per unit generated for the OGLCGEP was determined as US$cts 14.84/kWh. Table 4 shows the OGLCGEP long-run marginal cost (LRMC) in the RDFS. The generation companies (GENCOs) would use the LRMC as an average tariff for selling power to the power distribution company. The rate would determine their present value (PV) inflows from power generation.

***Table 4:** OGLCGEP LRMC – RDFS*

Year	Energy (GWh) {2nd}	Energy (GWh) {1st}	Energy Differ. (GWh)	LRMC Factor	Energy Disco. (GWh)	Opern Cost (M$) {2nd}	Opern Cost (M$) {1st}	Opern Cost (M$) Differ.	Capital (M$) {2nd}	Capital (M$) {1st}	Capital Cost (M$) Differ.
				8.0							
2010	7772	7721	51.00	1.00	51.00	806.30	765.20	41.10	1419.34	1398.03	21.31
2011	8127	8047	80.00	0.93	74.07	502.10	479.80	20.65	614.22	593.05	19.60
2012	9496	9422	74.00	0.86	63.44	208.40	200.30	6.94	575.17	566.00	7.86
2013	11017	10944	73.00	0.79	57.95	222.50	215.40	5.64	387.60	361.93	20.38
2014	12874	12800	74.00	0.74	54.39	185.90	185.00	0.66	509.91	527.08	-12.62
2015	15640	15566	74.00	0.68	50.36	254.10	249.70	2.99	877.78	902.45	-16.79
2016	18038	17963	75.00	0.63	47.26	296.00	291.40	2.90	1374.70	1385.20	-6.62
2017	20707	20632	75.00	0.58	43.76	346.20	351.40	-3.03	1638.73	1663.71	-14.58
2018	23579	23503	76.00	0.54	41.06	441.70	436.90	2.59	1322.53	1322.53	0.00
2019	26491	26416	75.00	0.50	37.52	522.70	518.40	2.15	1388.58	1388.58	0.00
2020	29867	29793	74.00	0.46	34.28	615.00	610.70	1.99	2325.55	2325.55	0.00
2021	33835	33759	76.00	0.43	32.60	674.80	671.00	1.63	2537.15	2537.15	0.00
2022	37970	37895	75.00	0.40	29.78	737.70	733.50	1.67	2205.99	2205.99	0.00
2023	42575	42501	74.00	0.37	27.21	887.10	882.60	1.65	3154.58	3154.58	0.00
2024	47739	47665	74.00	0.34	25.19	1016.20	1011.60	1.57	3698.46	3748.62	-17.08
2025	53508	53433	75.00	0.32	23.64	1058.50	1054.50	1.26	3284.64	3267.92	5.27
2026	59762	59681	81.00	0.29	23.64	1142.30	1126.20	4.70	3690.28	3656.84	9.76
2027	66944	66869	75.00	0.27	20.27	1376.40	1371.30	1.38	2259.63	2259.63	0.00
2028	74983	74910	73.00	0.25	18.27	1486.60	1481.60	1.25	1429.47	1429.47	0.00
2029	84000	83920	80.00	0.23	18.54	1695.60	1691.00	1.07	2102.10	2102.10	0.00
2030	93935	93861	74.00	0.21	15.88	2082.50	2077.40	1.09	1003.06	1003.06	0.00
2031	105846	105766	80.00	0.20	15.89	2307.90	2301.60	1.25	0.00	0.00	0.00
Total	884705	883067	1638		806.02	18866.50	18706.50	103.11	37799.47	37799.47	16.50
					Bus						
					(US$ct/kWh)						
					Opern	12.79					
					Capital	2.05					
					LRMC	14.84					

On the other hand, the optimal energy system's cost for the OGLCGEP was determined as US$ 14.62 billion with a salvage value of US$ 1.09 billion by 2031. This would be the minimum possible generation system's cost minimized in the overall objective cost function in the WASP IV model. Subsequently, the net present value (NPV) for the OGLCGEP was determined as US$ 2.16 billion at the optimal energy system's cost. Table 5 present the financial flows of the OGLCGEP for the RDFS. The results show that the NPV would grow towards positive as the system tends towards 2031. In fact, it would break even around 2029-2030.

***Table 5:** OGLCGEP Financial Flows – RDFS*

Year	PV – Inflows (US$ Billions)	Salvage Value (US$ Billions)	System's Cost (US$ Billions)	NPV (US$ Billions)
2031	15.70	1.09	14.62	2.16
2030	13.93	0.89	14.08	0.74
2029	12.45	0.93	13.48	-0.10
2028	11.12	0.74	12.83	-0.97
2027	9.92	0.42	12.14	-1.79
2026	8.86	0.58	11.52	-2.09
2025	7.93	0.54	10.76	-2.30
2024	7.07	0.31	9.93	-2.55
2023	6.31	0.58	9.23	-2.34
2022	5.62	0.32	8.25	-2.31
2021	5.01	0.26	7.43	-2.16
2020	4.42	0.15	6.62	-2.05
2019	3.92	0.11	5.98	-1.95
2018	3.49	0.17	5.38	-1.72
2017	3.06	0.10	4.74	-1.58
2016	2.67	0.12	4.08	-1.30
2015	2.31	0.05	3.29	-0.93
2014	1.90	0.00	2.83	-0.93
2013	1.62	0.00	2.70	-1.08
2012	1.40	0.11	2.54	-1.03
2011	1.19	0.00	1.16	0.03
2010	1.15	0.00	0.74	0.41

3.2 Higher Demand Forecast Scenario (HDFS)

3.2.1 Capacity Mix

The optimal solution in the HDFS was obtained with higher proportions of RE capacity additions in comparison to the RDFS. Table 6 presents the annual RE capacity addition schedule in the HDFS. The results in table show that all candidate plants except imports and hydropower will increase with reference to the RDFS during the planning period. The RE generation capacities will be added as follows relative to the RDFS; geothermal 7420MW to 9940MW; wind 3400MW to 4500MW; nuclear doubled from 1800MW; natural gas from 2160MW to 3780MW and solar PV 200MW to 300MW. In consequence, the total RE capacity additions of 17380MW (RDFS) will increase to 24520MW (HDFS). On aggregate, geothermal at 40.5% will account for the highest total capacity additions while hydropower at 0.8% the least.

Table 6: *OGLCGEP RE Capacity Addition Schedule (MW) – HDFS*

Year	Geothermal (140MW)	Wind (100MW)	Nuclear (600MW)	Imports (200MW)	Natural Gas (180MW)	Solar PV (100MW)	Mutonga Hydro (60MW)	LGF (140MW)	Total Added Capacity(MW)
2010	-	-	-	-	-	-	-	-	0
2011	-	-	-	-	-	-	-	-	0
2012	1×140	-	-	-	-	-	-	-	140
2013	1×140	-	-	-	-	-	-	-	140
2014	-	-	-	-	-	-	-	-	0
2015	2×140	1×100	-	-	-	-	-	-	380
2016	3×140	1×100	-	-	1×180	-	-	-	700
2017	2×140	-	-	1×200	-	-	-	-	480
2018	2×140	1×100	-	1×200	-	-	1×60	1×140	780
2019	3×140	2×100	-	-	1×180	-	-	-	800
2020	3×140	2×100	-	1×200	-	-	-	-	820
2021	4×140	1×100	-	1×200	-	1×100	-	-	960
2022	1×140	1×100	1×600	-	1×180	-	-	-	1020
2023	-	-	2×600	-	-	-	-	-	1200
2024	4×140	2×100	-	1×200	2×180	-	-	-	1320
2025	6×140	3×100	-	1×200	1×180	-	-	-	1520
2026	5×140	7×100	-	1×200	-	-	-	-	1600
2027	-	1×100	1×600	4×200	2×180	1×100	-	-	1960
2028	9×140	3×100	-	-	3×180	-	-	-	2100
2029	8×140	1×100	2×600	-	-	-	-	-	2420
2030	9×140	10×100	-	-	3×180	-	-	-	2800
2031	8×140	9×100	-	-	7×180	1×100	-	-	3380
Total	**71**	**45**	**6**	**11**	**21**	**3**	**1**	**1**	**159**
	9940	**4500**	**3600**	**2200**	**3780**	**300**	**60**	**140**	**24520**
%	**40.5%**	**18.4%**	**14.7%**	**9.0%**	**15.4%**	**1.2%**	**0.8%**		**100%**

The OGLCGEP capacity in the HDFS was derived as shown in table 7. The results show that the generation capacities were entirely the same as the RDFS for the base year. However, the rising annual RE capacity additions at an average rate of 1226MW would vary the generation capacity to 26968MW at peak demand of 22985MW in 2031. This would be relatively higher than the corresponding 19828MW capacity at 16905MW peak demand in the RDFS. The capacities in the HDFS would demonstrate higher annual LOLPs averaged at 3.02% as opposed to 1.94% for the RDFS. By 2031, the generation capacity would 71% green and dominated by geothermal (39.4%) and wind (18.5%) of the total.

Table 7: *OGLCGEP Capacity (MW) – HDFS*

Year	Hydropower	Natural Gas	HFO	Nuclear	Imports	Baggase	Kerosene	Geothermal	Solar PV	Wind	System's Capacity	Peak Load	% LOLP
2010	761	0	332	0	0	26	60	198	0	6	1382	1227	23.265
2011	761	0	452	0	0	26	60	198	0	6	1502	1331	9.877
2012	761	0	452	0	0	26	60	346	0	6	1649	1584	20.337
2013	761	0	704	0	0	26	60	651	0	126	2326	1877	0.205
2014	814	0	704	0	0	26	0	1071	0	476	3089	2236	0.013
2015	839	0	704	0	0	26	0	1306	0	576	3449	2760	0.692
2016	839	180	704	0	0	26	0	1726	0	676	4149	3207	0.096
2017	839	180	704	0	200	26	0	2051	0	676	4674	3749	0.233
2018	1039	180	704	0	400	26	0	2331	0	776	5454	4322	0.150
2019	1039	360	648	0	400	0	0	2751	0	976	6172	4970	0.344
2020	1039	360	648	0	600	0	0	3171	0	1176	6992	5703	0.552
2021	1039	360	574	0	800	0	0	3731	100	1276	7878	6521	0.861
2022	1039	540	574	600	800	0	0	3871	100	1376	8898	7397	0.877
2023	1039	540	514	1800	800	0	0	3871	100	1376	10038	8388	0.860
2024	1039	900	514	1800	1000	0	0	4431	100	1576	11358	9509	0.714
2025	1039	1080	461	1800	1200	0	0	5271	100	1876	12826	10778	0.729
2026	1039	1080	461	1800	1400	0	0	5971	100	2576	14426	12217	1.301
2027	1039	1440	461	2400	2200	0	0	5971	200	2676	16386	13847	1.074
2028	1039	1980	461	2400	2200	0	0	7183	200	2976	18438	15697	1.039
2029	1039	1980	461	3600	2200	0	0	8303	200	3076	20858	17796	0.835
2030	1039	2520	461	3600	2200	0	0	9493	200	4076	23588	20156	1.155
2031	1039	3780	461	3600	2200	0	0	10613	300	4976	26968	22985	1.222
%	**3.9%**	**14.0%**	**1.7%**	**13.3%**	**8.2%**	**0**	**0**	**39.4%**	**1.1%**	**18.5%**	**100%**		**3.02**

3.2.2 Energy Mix and CO_2 Emissions

The OGLCGEP energy for the HDFS would be capable of meeting the prevailing demand over the planning horizon. Fig 6 presents the OGLCGEP energy mix in the HDFS. The results show that the energy mix would increase from 7721 GWh in the base year to 143830GWh in 2031. This will be higher than the corresponding system's energy of 105766GWh in the RDFS.

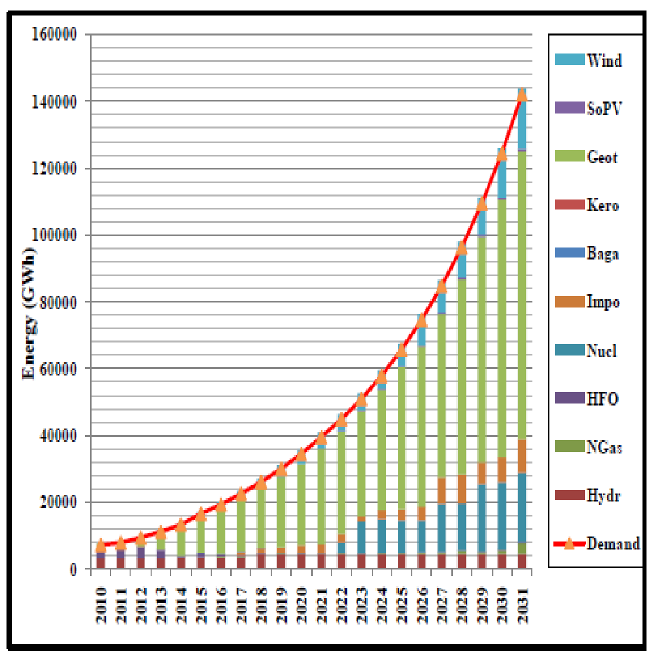

Figure 6: *OGLCGEP Energy (GWh) – HDFS*

Consequently, the energy system would emit some CO_2 emission over the planning period. Fig 7 illustrates the profile for the CO_2 emissions for the OGLCGEP in the HDFS. The results show that the annual CO_2 emissions will grow from

0.73 Mt CO_2 in the base year same as in the RDFS to 2.9 Mt CO_2 in 2031. However, the varying RE supply additions from the RDFS resulted in a cumulative total of 23.6Mt CO_2; 5.6 Mt CO_2 higher than the RDFS to be emitted by 2031. Similarly, geothermal would be the highest emitter at 73.7% of the total as in the HDFS. Moreover, like in the RDFS, Other RE such as hydropower, wind and solar PV would have no emissions at all.

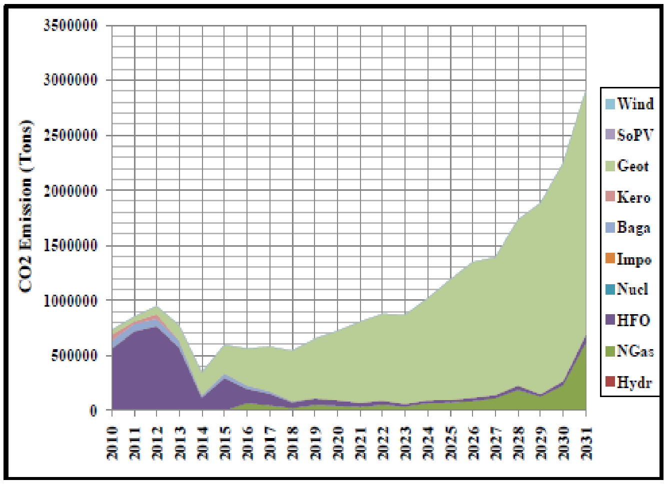

Figure 7: *OGLCGEP CO_2 Emission – HDFS*

3.2.3 Generation Economics

The average power tariff per unit generated was determined as US\$cts 17.85/kWh /kWh. Table 8 shows the OGLCGEP LRMC in the HDFS. The results GENCOs would sell power to power distributing companies at an average of US\$cts 3.01/kWh higher in the HDFS than in the RDFS. As a result, the rate would depict higher present value (PV) inflows from power generation than in the RDFS.

Table 8: *OGLCGEP LRMC – HDFS*

Year	Energy (GWh) {2nd}	Energy (GWh) {1st}	Energy Diff. (GWh)	LRMC Factor	Energy Disc. (GWh)	Opern Cost (M\$) {2nd}	Opern Cost (M\$) {1st}	Opern Cost (M\$) Differ.	Capital (M\$) {2nd}	Capital (M\$) {1st}	Capital Cost (M\$) Diff.
				8.0							
2010	7742	7721	21.00	1.00	21.00	782.2	765.20	17.00	1154.80	1154.80	0.00
2011	8236	8210	26.00	0.93	24.07	537.1	528.00	8.43	893.16	893.16	0.00
2012	9707	9685	22.00	0.86	18.86	707.3	694.40	11.06	926.15	926.15	0.00
2013	11666	11636	30.00	0.79	23.81	429.6	425.00	3.65	1045.88	1045.88	0.00
2014	13895	13863	32.00	0.74	23.52	232.3	230.40	1.40	1428.94	1428.94	0.00
2015	17138	17106	32.00	0.68	21.78	362.2	358.70	2.38	1551.58	1551.58	0.00
2016	20126	20095	31.47	0.63	19.83	347.3	345.00	1.45	2552.12	2377.56	110
2017	23523	23491	32.26	0.58	18.82	417.3	415.30	1.17	2760.65	2819.10	-34.1
2018	27112	27080	32.00	0.54	17.29	450.4	448.70	0.92	2183.19	2250.64	-36.4
2019	31171	31142	29.00	0.50	14.51	514.6	512.80	0.90	2211.68	2333.12	-60.8
2020	35764	35733	31.00	0.46	14.36	596.5	594.80	0.79	2856.63	2843.94	5.88
2021	40890	40859	31.00	0.43	13.30	647.4	669.30	-9.39	2930.59	2870.48	25.8
2022	46378	46349	29.00	0.40	11.52	855.9	854.20	0.68	2544.21	2544.21	0.00
2023	52586	52554	32.00	0.37	11.77	1102.2	1100.60	0.59	4353.31	4181.71	63.1
2024	59612	59581	31.00	0.34	10.55	1267.2	1265.60	0.54	5160.33	5217.53	-19.5
2025	67565	67535	30.00	0.32	9.46	1357.1	1383.70	-8.39	4926.8	5041.20	-36.1
2026	76338	76307	31.00	0.29	9.05	1537.2	1535.60	0.47	4729.41	4729.41	0.00
2027	86523	86493	30.00	0.27	8.11	1993.7	1991.90	0.49	2825.00	2825.00	0.00
2028	98052	98052	0.00	0.25	0.00	2212.9	2212.90	0.00	2690.33	2690.33	0.00
2029	111167	111167	0.00	0.23	0.00	2464.9	2464.90	0.00	3355.86	3355.86	0.00
2030	125907	125907	0.00	0.21	0.00	2766.5	2766.50	0.00	1384.71	1384.71	0.00
2031	143830	143830	0.00	0.20	0.00	3388	3388.00	0.00	0.00	0.00	0.00
Total	1114929	1114396	532.7		291.6	24969.8	24951.5	34.12	54465.3	54465.3	17.9

Bus	
US\$cts/kWh	
Opern	11.70
Capital	6.15
LRMC	17.85

Conversely, the optimal energy system's cost for the OGLCGEP was determined as US\$ 19.96 billion at a salvage value of US\$ 1.37 billion by 2031 in the HDFS. In this case, the system's cost was US\$ 5.34 billion higher than the RDFS. Subsequently, the NPV for the OGLCGEP was US\$ 7.08 billion at the optimal energy system's cost; US\$ 4.92 billion higher than the RDFS. Table 9 present the financial flows of the OGLCGEP for the HDFS. The results show that the NPV would grow towards positive as the system tends towards 2031 similar to the RDFS. In fact, it would break even around 2027-2028 but a year earlier than the RDFS.

Table 9: *OGLCGEP Financial Inflows & Outflows – HDFS*

Year	PV – Inflow (US\$ Billions)	Salvage Value (US\$ Billions)	System's Cost (US\$ Billions)	NPV (US\$ Billions)
2031	25.67	1.37	19.96	7.08
2030	22.47	1.30	19.19	4.59
2029	19.84	1.64	18.35	3.13
2028	17.50	0.98	17.32	1.17
2027	15.44	0.66	16.34	-0.24
2026	13.62	0.70	15.47	-1.14
2025	12.05	0.64	14.50	-1.80
2024	10.64	0.44	13.46	-2.38
2023	9.38	0.85	12.52	-2.28
2022	8.27	0.55	11.19	-2.37
2021	7.29	0.41	10.10	-2.39
2020	6.38	0.28	9.03	-2.37
2019	5.56	0.27	8.08	-2.25
2018	4.83	0.30	7.04	-1.91
2017	4.19	0.12	5.96	-1.64
2016	3.59	0.20	5.21	-1.42
2015	3.05	0.12	4.00	-0.82
2014	2.47	0.00	3.04	-0.56
2013	2.08	0.04	2.87	-0.75
2012	1.73	0.04	2.18	-0.42
2011	1.47	0.00	1.21	0.26
2010	1.38	0.00	0.74	0.64

3.3 The OGLCGEP Sensitivity Analyses

3.3.1 Variations in Discount Rate on System's Cost and NPV of the OGLCGEP

When the discount rate was varied between 8% and 12%; the energy system's cost of the OGLCGEP decreased while NPV increased in the RDFS and HDFS. Table 10 shows the variations in the discount rate on system's cost and NPV of the OGLCGEP. The results show that the system's cost will decrease at the rate of US\$ 0.97 to US\$ 1.34 billion per % discount rate increase in the RDFS and HDFS respectively. Conversely, the NPV will increase at a lower rate of US\$ 0.82 to US\$ 1.15 billion per % discount rate increase in the RDFS and HDFS respectively. Despite these discount rate variations, the total number of generation plants remained unchanged in both scenarios.

Table 10: *Variations in Discount Rate on System's Cost and NPV of the OGLCGEP*

Discount	System's Cost (US\$ Billions)		NPV (US\$ Billions)	
Rate	RDFS	HDFS	RDFS	HDFS
8%	14.62	19.96	2.16	7.08
10%	12.49	17.03	3.94	9.56
12%	10.75	14.62	5.44	11.68

3.3.2 Variation in Fuel Cost on System's Cost and NPV of the OGLCGEP

When the fuel cost was increased by 10% to 30%, the energy system's cost of the OGLCGEP in the RDFS and HDFS increased slightly whereas the NPV reduced marginally. Table 11 shows variations in fuel cost on system's cost and NPV of the OGLCGEP. The results show that the system's cost will increase at the rate of US$ 0.03 to US$ 0.07 billion per % fuel cost increase in the RDFS and the HDFS respectively. Similarly at the same rate as the above system's cost increase, the NPV will decrease in both scenarios. In spite of these fuel cost variations, the total number of plants remained constant in both scenarios.

***Table 11:** Variations in Fuel-Cost on System's Cost and NPV of the OGLCGEP*

Fuel Cost	System's Cost (US$ Billions)		NPV (US$ Billions)	
	RDFS	HDFS	RDFS	HDFS
10%	13.64	18.65	3.15	8.39
20%	13.71	18.79	3.08	8.25
30%	13.77	18.92	3.02	8.12

3.3.3 Variations in Capital Cost on System's Cost and NPV of the OGLCGEP

When the capital cost was increased by 5% to 15%, the energy system's cost of the OGLCGEP narrowly increased while the NPV decreased slightly in each scenario. Table 12 shows the variations in capital cost on system's cost and NPV of the OGLCGEP. The results show that the capital cost will increase at the rate of US$ 0.2 to US$ 0.28 billion per % increase in the RDFS and the HDFS respectively. On the contrary, the NPV will decrease at a lower rate of US$ 0.17 to US$ 0.25 billion per % increase in the RDFS and the HDFS respectively. Despite these capital cost variations, the total number of plants remained the same in both scenarios.

***Table 12:** Variations in Capital Cost on System's Cost and NPV of the OGLCGEP*

Capital Cost	System's Cost (US$ Billions)		NPV (US$ Billions)	
	RDFS	HDFS	RDFS	HDFS
10%	15.02	20.52	1.82	6.59
20%	15.41	21.08	1.49	6.10
30%	15.81	21.64	1.14	5.61

4.0 Discussions

The OGLCGEP generation capacity was projected to grow from 1382MW at 1227MW peak demand in the base year to 19828MW at a peak demand of 16905MW in the RDFS and 26968MW capacity at a peak demand of 22985MW in the HDFS. In the base year, the generation capacity was predominantly hydropower in both scenarios. It was 55% hydropower and 24% HFO with the least reserve capacity hence the highest LOLP of 23.3%. However, the RES capacity additions over the planning horizon changed the entire generation portfolio. In the RDFS, the generation capacities would be 78% green and dominated by geothermal (40.8%) wind (19.2%) by 2031. Additionally, the capacities would characterized by low annual LOLPs averaged at 1.94% over the planning horizon. In the HDFS, the generation capacities would 71% green and predominantly geothermal (39.4%) and wind (18.5%) by 2031. However, the capacities would be characterized by relatively higher annual LOLPs of 3.02% on average. According to [5] and [20]; high LOLP(s) portrayed low generation reliability to meet the requisite demand. Conversely, low LOLP(s) depicted high generation reliability. Thus, the hydro power dominated generation in the base year was vulnerable to power shortfalls due to recurrent droughts hence low reliability. [13], [14] reported drought as the most frequent occurrence in Kenya citing cases in 1991–1992, 1995–1996, 1998–2000, 2004–2005, 2009 and projecting more to persist. Therefore, a more reliable generation than the base year based on increasing geothermal/wind capacity additions over the planning horizon were the focus of the GEP study. These were low carbon and climate resilient energy resources declared in [2]; [3], [6], [13]with substantial capabilities of not only mitigating CO_2 emissions but also for security of power. On the contrary, the planned energy system for the OGLCGEP would supply 7721GWh in the base year to 105766 GWh in the RDFS and 143830GWh in the HDFS by 2031. Subsequently, the system's cumulative total of 18 and 23.6Mt CO_2 emissions in the RDFS and HDFS respectively would prevail. Consequently, a business opportunity from carbon credits tradable on the carbon market similar to those acknowledged by [7] in India prevailed for green generation growth over the convention generation systems in Kenya [13]. As a matter of fact, Kenya can develop numerous projects with potential emission reduction capabilities to enhance environmental sustainability through the clean management mechanisms (CDM) under the Kyoto Accord. In Kenya, there was a lot of potential for CDM projects in the future given that just a few have been set up [15]. For this reason, the OGLCGEP that is 71 to 78% green encompass potential RE similar to those documented by [7], [9] as CDM candidates. Nevertheless, low carbon credits' revenue due to low carbon market prices discouraged implementation of the CDM in many countries in the world as observed by [9]. However, [8]was optimistic that proper price regulations as well as thorough and timely approval of CDM projects would stimulate rapid growth in RE generation investment in CDM in the near future. This is in addition to other fringe benefits of sustainable development such as health benefits, green jobs and foreign exchange savings [10], [11]. The planned energy system's cost consisting of the existing and the candidate generation plants for the OGLCGEP was projected to be US$ 14.62 billion in the RDFS; US$ 5.34 billion higher in the HDFS by 2031. Conversely, its NPV would be US$ +2.16 billion in the RDFS; US$ +4.92 billion higher in the HDFS by 2031. As a matter of fact, the optimal system's cost was the lowest possible cost at the highest and positive system's NPV in each scenario. This relationship was similar to [5], [25], [26] remarks on feasible projects hence the envisaged energy system a viable generation investment proposition in the OGLCGEP. During the sensitivity analyses, an increase in the % discount rate showed that the energy system's cost would decrease at the rate of US$ 0.97 to US$ 1.34 billion per % discount rate increase in the RDFS and HDFS respectively. In contrast, the NPV would increase at a slightly lower rate of US$ 0.82 to US$ 1.15 billion per % discount rate increase in the RDFS and HDFS respectively. On the contrary, an increase in the capital cost would raise the energy system's cost at the rate of US$ 0.2 to US$ 0.28 billion per % capital cost increase in the RDFS and the HDFS respectively. Conversely, the NPV would decrease at a lower rate of US$ 0.17 to US$ 0.25 billion per % capital cost increase in the RDFS and the HDFS respectively. The inverse relationship between the energy system's cost and NPV during the variations was consistent with inferences by [5] [26]. In spite of the above effects; the changes in the

ISSN 2347-4289

fuel cost showed unique effect on the system's cost and NPV. In this case, an increase in the fuel cost showed that the energy system's cost would increase at the rate of US$ 0.03 to US$ 0.07 billion per % fuel cost increase in the RDFS and the HDFS respectively. By way of contrast, the NPV robustly decreased at exactly the same rate as the above system's cost increase in each scenario. Yet, an increase in fuel cost would significantly escalate the energy system's cost over the NPV as remarked by [25], [26]. Contrastingly, the OGLCGEP was less sensitive to fuel cost rise because of its majorly fuel-free RE power generation similar to those indicated in [4]. Despite the discount rate, fuel cost and capital cost variations; the total number of plants remained constant in both scenarios. This was another striking indicator of the RE system's stability to variation in economic parameters.

5.0 Conclusions and Recommendation

The derived optimal green least cost generation expansion plan (OGLCGEP) will have the generation capacity of 1382MW at 1227MW peak demand in the base year to 19828MW at a peak demand of 16905MW in the RDFS and 26968MW capacity at a peak demand of 22985MW in the HDFS by 2031. In the RDFS, the generation capacities would be 78% green and dominated by geothermal (40.8%) wind (19.2%) by 2031 and characterized by a modest annual reliability averaged at 1.94% LOLP. In the HDFS, the generation capacities would 71% green and predominantly geothermal (39.4%) and wind (18.5%) by 2031 with relatively higher annual LOLPs of 3.02% on average. On the contrary, the planned energy system for the OGLCGEP would supply 7721GWh in the base year to 105766 GWh in the RDFS and 143830GWh in the HDFS by 2031. Consequently, the energy system's cumulative total of 18 and 23.6Mt CO_2 emissions in the RDFS and HDFS respectively presenting a business opportunity from carbon credits tradable as market revenues for green generation growth in Kenya through the clean management mechanisms (CDM). In addition , the planned energy system's cost consisting of the existing and the candidate generation plants for the OGLCGEP was projected to be US$ 14.62 billion in the RDFS; US$ 5.34 billion higher in the HDFS by 2031. Subsequently, the energy system's NPV would be US$ +2.16 billion in the RDFS; US$ +4.92 billion higher in the HDFS by 2031 besides potential carbon credits. For this reasons, the envisaged energy system would be a viable generation investment hence the future for higher RE grid integration for Kenya. Therefore, the research recommends future studies to focus on modeling of the Kenya national-grid reliability and stability with high penetration of variable renewable energy sources.

Acknowledgment

I would like to thank Dr. Oliver Johnson of the Stockholm Environmental Institute (SEI); Nairobi for his mentorship during the preparation of this paper. I also acknowledge the support provided by the SEI Write-shop to Support Developing of Country Publications on Transitions to Modern Energy Systems in which this paper was chosen. I declare that there was not conflict of interest in this research.

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